Pipeline Corrosion – Can it always be modelled with confidence?

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Pipeline Corrosion

- **Loss of Pipeline Integrity due to Corrosion**
- **Corrosion Modelling and Influencing Factors**
- **Comparison of Corrosion Prediction Models**
- **Material Selection**
- **Case Studies**
- **Conclusions**
Pipeline Corrosion
Our concern - Loss of pipeline integrity

(c) breakdown of North Sea pipeline incidents

<table>
<thead>
<tr>
<th>Average Incidents $10^3$ km year</th>
<th>Breakdown of Information %</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pipeline</td>
</tr>
<tr>
<td>0.14</td>
<td>65</td>
</tr>
</tbody>
</table>

Ref. Subsea Pipeline Engineering, Palmer & King, 2nd Ed, 2008

One oil company's breakdown of its actual corrosion failures averaged over several offshore fields (topside processing plant and pipelines)

<table>
<thead>
<tr>
<th>Corrosion Failure Mechanism</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon dioxide corrosion</td>
<td>32</td>
</tr>
<tr>
<td>Combined velocity and carbon dioxide corrosion</td>
<td>5</td>
</tr>
<tr>
<td>Chemical attack</td>
<td>1</td>
</tr>
<tr>
<td>Combined corrosion and fabrication defects</td>
<td>3</td>
</tr>
<tr>
<td>Microbiological corrosion</td>
<td>13</td>
</tr>
<tr>
<td>Corrosion of threaded items</td>
<td>11</td>
</tr>
<tr>
<td>Corrosion in dead legs</td>
<td>16</td>
</tr>
<tr>
<td>Erosion</td>
<td>8</td>
</tr>
<tr>
<td>Mechanical associated corrosion failures</td>
<td>2</td>
</tr>
<tr>
<td>Corrosion fatigue</td>
<td>1</td>
</tr>
<tr>
<td>External corrosion</td>
<td>7</td>
</tr>
</tbody>
</table>

The main culprits 60%
# Pipeline Corrosion

## CO₂ Corrosion of Carbon Steel

<table>
<thead>
<tr>
<th>CAUSES</th>
<th>OCCURRENCE</th>
<th>SUSCEPTIBLE SYSTEMS</th>
<th>INSPECTION / MONITORING METHODS</th>
<th>MANAGEMENT</th>
</tr>
</thead>
<tbody>
<tr>
<td>− Dissolved carbon dioxide, produces carbonic acid</td>
<td>− All water-wetted locations in hydrocarbon systems</td>
<td>− All (water containing) hydrocarbon processing systems</td>
<td>− Process parameter monitoring, e.g., temperature, pressure, dew point</td>
<td>− Corrosion resistant alloy</td>
</tr>
<tr>
<td>− Inadequate corrosion inhibition</td>
<td>− Pipework straights (6 o’clock)/bends/tees/reducers</td>
<td>− UT</td>
<td>− Chemical inhibition</td>
<td>− See EI Guidance Document, Appdx B, Sections 1, 6 and 13,</td>
</tr>
<tr>
<td></td>
<td>− Welds, heat affected zone and downstream of welds</td>
<td>− Radiography</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| DEGRADATION MORPHOLOGY                                                 |                                                                           |                                                          |                                 |                                      |
|------------------------------------------------------------------------|                                                                           |                                                          |                                 |                                      |
| General corrosion (flow influenced)                                    | Localised corrosion (low flow)                                           | Preferential weld corrosion                             |                                 |                                      |

Pipeline Corrosion
Carbon dioxide (CO$_2$) corrosion of carbon steel

Bottom of line

- Corrosion rate depends on
  - Fluid type and liquid velocity
  - Amount of acid gas
  - Pressure / temperature profile over distance & time
  - Water chemistry, bicarbonate and organic acid
  - Inhibitor availability and effectiveness.
Pipeline Corrosion
Modelling CO₂ Corrosion Rate of Carbon Steel

• Prediction of corrosion rate
  Traditionally based on empirical models, in particular that of de Waard et al. models
  More recently a trend towards mechanistic models, e.g. Ohio University Multicorp

• Require the presence of free water
  Production, condensation

• Calculate a bare steel corrosion rate based on measurable parameters
  Water chemistry, pCO₂ in vapour, T, pH, V, diameter, flow pattern
  Vapour CO₂ partial pressure proportional to CO₂ in water phase (Henry's Law)

• Also need to consider
  Scale protection, oil wetting and water entrainment by oil, glycol / methanol presence
Pipeline Corrosion
Modelling CO₂ Corrosion Rate of Carbon Steel

Ref. Paper 02235, NACE Corrosion 2002
Pipeline Corrosion
Modelling CO₂ Corrosion Rate of Carbon Steel - Effect of scale formation

![Graph showing the effect of temperature on the corrosion rate of carbon steel with and without scaling conditions. The graph indicates that the corrosion rate decreases with an increase in temperature. The diagram also highlights that the corrosion rate can be affected by various factors such as the amount of water, flow velocity, pH, or Fe²⁺ concentration.](image)
Pipeline Corrosion Modelling CO₂ Corrosion Rate of Carbon Steel - Effect of water entrainment

- Water entrainment does not occur with:
  - gas condensate due to the low specific gravity
  - Annular dispersed flow
  - Lower liquid velocities < 1.5 m/s

Liquid velocity > 1.5 m/s

![Graph showing corrosion rate vs watercut]
Pipeline Corrosion
Modelling CO$_2$ corrosion of carbon steel – Good fit with laboratory data

**Corrosion models**
- de Waard & Milliams
- Cassandra
- Hydrocor
- Norsok
- Ohio Model
- Many others

Some are conservative, some are not

Later models include flow, scale & pH factors

Latest models are mechanistic rather than empirical

**Carbon steel with corrosion allowance**

Total loss (with inhibitor)
- < 8mm for pipeline,
- < 6mm for piping,
- <3mm vessels

Assessment of risks
(Sensitivity to $\Delta$ in $T$, $P$, CO$_2$)

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**FIGURE 1** - Comparison of predicted CO$_2$ corrosion rates of 1995 model (IFE fit) with measured laboratory data. Upper and lower lines refer to +50% and -33% deviation.
Pipeline Corrosion Modelling CO₂ corrosion of carbon steel – Predicted rate depends on model

Six corrosion models compared to selected field data (IFE data)

- NORSOK M-506
- Hydrocor
- Cassandra
- de Waard model
- Lipucor
- ECE

Normalized corrosion rates (predicted/measured) for selected field data (Ref. Paper 06118, NACE Corrosion 2006)
Pipeline Corrosion
When to select carbon steel?

• Virtually all corrosion issues/failures are localized initiated under non-steady state excursions

• Probably never been a case of failure by uniform corrosion!

• However, most predictive corrosion models are based on general or uniform corrosion concepts.

• Don’t ignore existing performance data and experience when it is available

• Uncertainties and a lack of consensus? Consider accelerated laboratory and long term field testing.
Pipeline Corrosion
Modelling CO₂ corrosion of carbon steel – Top of line (TOL)

- In most cases TOL corrosion rate less than 0.1mm/yr
- TOL corrosion is a concern at high water condensation rates
- Cold spots or non-insulated sections at inlet side of subsea pipelines
- High inlet temperatures above 80°C aggravated by high CO₂ partial pressures and acetic acid
Pipeline Corrosion
Corrosion rate prediction for high H₂S production fluids

Corrosion of carbon steel

- No models available to accurately predict corrosion when ratio drops below 500
- Mixed corrosion regime, pCO₂/pH₂S < 500
  - pitting corrosion rate within modelled uniform CR$_{CO2}$
- H₂S corrosion regime, pCO₂/pH₂S < 500
  - severe localised pitting at 2-3 x CR$_{CO2}$
  - no general corrosion.
I want to use Carbon Steel?
What is the corrosion rate?
Can I trust the model?
Maybe I will opt for CRA or cladding
Pipeline Corrosion
CRAs & Cladding – A saviour or gold plated solution?

<table>
<thead>
<tr>
<th>Pipeline material</th>
<th>Relative £</th>
</tr>
</thead>
<tbody>
<tr>
<td>Carbon steel (x65)</td>
<td>1</td>
</tr>
<tr>
<td>Carbon steel (x65) + SS 316L internal lining</td>
<td>3</td>
</tr>
<tr>
<td>Carbon steel (x65) + SS 316L internal clad</td>
<td>5</td>
</tr>
<tr>
<td>22% Cr duplex stainless steel</td>
<td>5</td>
</tr>
<tr>
<td>Carbon steel (x65) + Ni alloy 625 internal lining</td>
<td>6</td>
</tr>
<tr>
<td>Carbon steel (x65) + Ni alloy 625 internal clad</td>
<td>10</td>
</tr>
</tbody>
</table>
Pipeline Corrosion
An Asset Life Cycle – Materials selection often occurs at Create stage

Create

- Front End Thinking
  - Field Development Planning
  - Concept Definition/Pre-FEED
  - Visualisation Studies
  - Reference Class Forecasting

Realise

- Optimised Engineered Solutions
  - FEED
  - Detailed Design
  - Engineering Support
  - Project Management Services

Enhance

- Protected, Maximised Value
  - Late Life Operation/Extension
  - Deboottlenecking & Brownfield Modifications
  - Decommissioning & Restoration
  - Asset Integrity

Specialist Technical Services

Specialist Capabilities

Proprietary Tools & Processes
Case Study:: UAE NW Fields Development - Project Scope

Fields Included in the NW Development

Core Reserves

*Satah* gas reserves (CO\(_2\) 7%, H\(_2\)S 1.5%, 120\(^\circ\)C)

*Hair Dalma & Dalma* oil reserves (CO\(_2\) 4%, H\(_2\)S 20%, 80\(^\circ\)C)

*Hair Dalma* gas reserves (CO\(_2\) 9%, H\(_2\)S 0%, 120\(^\circ\)C)

Project Development

Concept Select - Genesis

Further Studies – Genesis (Pipeline Materials)

Pre-Feed – Underway

Feed -- Starting
UAE NW Fields Development – Lifecycle Cost Analysis

<table>
<thead>
<tr>
<th>Gathering Pipeline System</th>
<th>Life Cycle Cost (Relative)</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>CS</td>
<td>CS + CRA clad</td>
</tr>
<tr>
<td>Pipeline 1</td>
<td>1</td>
<td>3</td>
</tr>
<tr>
<td>Pipeline 2</td>
<td>3</td>
<td>8</td>
</tr>
<tr>
<td>Pipeline 3</td>
<td>2.5</td>
<td>7</td>
</tr>
<tr>
<td>Pipeline 4</td>
<td>2</td>
<td>5</td>
</tr>
</tbody>
</table>

Possible Materials

**Main pipelines**
- Carbon steel with CA
- Corrosion inhibitor for H₂S corrosion
- Regular pigging

**Other components & equipment**
- CRA clad carbon steel
- CRA weld overlay
- Solid CRA
- UNS N08904, N08825, N06625
Difficulties in selecting pipeline materials

- Corrosion assessment and modelling of corrosion rate conducted, but not reliable with available models.
- For high H₂S, no uniform corrosion but severe pitting corrosion dominates.

Approach

- Desktop study
  - Corrosion assessment & materials selection, know the limitations
- Review of historical developments
  - Gulf region, Canada, Caspian Sea
- Chemical supplier experience & recommendations
- Accelerated corrosion testing
  - Carbon steel flow loop corrosion studies with inhibitor (general corrosion & pitting)
- Independent expert review
Corrosion testing to support carbon steel for high CO$_2$ / H$_2$S production fluids

LPR derived corrosion rates during flow loop test

- 4.5 bar CO$_2$, 1 bar H$_2$S, 120°C
- 100 ppm corrosion inhibitor
• Production pipelines are CS plus a corrosion allowance with both batch and continuous inhibitor injection, and biocide treatment required as part of the pipeline corrosion management plan

• Inhibitor suppliers confirm that effective inhibitors have been developed for fluids up to ~150°C

    Reformulation of the inhibitor system is required for application and supply in the UAE, particularly with respect to the carrier solvent

• Laboratory testing is necessary to confirm the performance of the reformulated inhibitors. This testing is being initiated with chemical suppliers

• Pipeline components and process facilities piping and equipment are required to be CRA
**PROJECT DESCRIPTION**

Operability assessment to determine the suitability of an infield pipeline system for asset life extension.

Two pipelines were already operating beyond the original design life of 10 years.

The workscope was run in 3 phases:

I. Pipeline system current condition assessment  
II. Corrosion Modelling using Cassandra, ECE and NORSOK  
III. Corrosion Risk Assessment and subsequent proposed updates to Integrity management strategy for pipeline life extension – short and long term
Corrosion Prediction v Measured data

Design vs Operational Consumption of CA (6MM) Based on Corrosion Modelling & CI Availability

Measured data
OUTCOME

Recommendations were made to:

• Determine internal condition of entire pipeline system
• Review and update Chemical injection programme
• Update sampling and monitoring programme
• Post ILI Asset Life Extension study to practicably update the Integrity Management Strategy, specifically Corrosion and Inspection management activities to meet extended life required.
Can pipeline corrosion be modelled with confidence? Usually Yes, but…….

- Know the limitations when modelling corrosion
- Corrosion modelling should only be considered as be part of an overall corrosion risk assessment methodology
- Consider existing corrosion rate data and experience with similar production fluids when it is available to backup corrosion modelling
- When there is uncertainty consider accelerated corrosion testing to support corrosion assessment
Thank You

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